Comment 1

The Industry recommends BLM follow current industry standards; this would be consistent with proposed changes in 43 CFR 3100, subpart 3154, which states "(a) To measure and report gas production from Federal and Indian lands, you must use a measurement system that – (1) Has an established industry standard (i.e., American Petroleum Institute (API), American Gas Association (AGA), American Society of Testing and Materials (ASTM), American National Standards Institute (ANSI)) for the accuracy, installation, operation, and maintenance of the meter…" Industry is concerned that following the proposed NTL in its present form will result in inconsistent interpretation of requirements.

Following industry standards eliminates inconsistent interpretation of requirements.

Industry recommends compliance with API MPMS Chapter 21.1 without the modifications proposed by BLM, as the existing requirements of 21.1 are definitive.

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Industry recommends BLM follow current industry standards; this would be consistent with proposed changes in 43 CFR 3100, subpart 3154, which states "(a) To measure and report gas production from Federal and Indian lands, you must use a measurement system that – (1) Has an established industry standard (i.e., American Petroleum Institute (API), American Gas Association (AGA), American Society of Testing and Materials (ASTM), American National Standards Institute (ANSI)) for the accuracy, installation, operation, and maintenance of the meter…" Industry is concerned that following the proposed NTL in its present form will result in inconsistent interpretation of requirements.

The modifying of currently accepted industry standards as occurs throughout the document is of great concern. The standard development process incorporates input from many sources, which results in viable, practical, and fair measurement practices. Of specific concern regarding this issue are the many locations where measurement occurs after natural gas is commingled and where some of the measured gas does not fall under BLM jurisdiction. Should this be allowed to happen, existing contracts and other legal agreements would be in direct conflict with the proposed NTL.

In the United States, much of the custody transfer of natural gas occurs among publicly held and privately owned companies such as producers, gatherers, processors, pipeline companies, local distribution companies, end-users, and others. Gas measurement is commonly based on standards and reports produced by the natural gas industry, and usually developed through one or more industry organizations. The writing of these standards and reports is an arduous task, and based on technically supported information originating from many different sources.

In an effort to draw comments from as many different resources as possible, some of the industry organizations make public their plans for the development of measurement standards in the Federal Register each year, thus allowing all interested parties to participate, including the BLM.

Even so, the BLM has apparently elected not to actively participate on such measurement standard writing committees, thus rendering the BLM ineffective in dealing with many of the issues addressed in the proposed NTL. Instead, the BLM has chosen to develop its own standards, through the NTL, and without due consideration of certain existing technical measurement standards which are commonly accepted and used throughout the natural gas industry in the United States and elsewhere.

Technical correctness is crucial in any NTL relating to natural gas measurement. A lack of technical correctness causes confusion within the natural gas industry and within the BLM. Technical correctness also ensures consistent interpretation among the many BLM representatives responsible for monitoring and enforcement. Clarity is also important because without a concise understanding of the meaning of the rules they become virtually impossible to follow, and neither BLM employees nor industry personnel responsible for gas measurement are able to follow them.

The modifying of currently accepted industry standards as occurs throughout the document is of great concern. The standard development process incorporates input from many sources, resulting in viable, practical, and fair measurement practices.

Of specific concern regarding this issue are the many locations where measurement occurs after natural gas is commingled and where some of the measured gas does not fall under BLM jurisdiction. Should this be allowed to happen, existing contracts and other legal agreements could be in direct conflict with the proposed NTL.

Consistent interpretation of the proposed NTL by the BLM is very important especially for natural gas producers, and other organizations responsible for measurement, which operate in more than one geographical area in which the BLM has an interest. In the past, BLM representatives in different areas have been inconstant in their interpretation of some of the BLM rules and orders, thus resulting in increased operating costs and potentially causing a measurement bias.

Technical correctness is crucial in any such document in order to reduce confusion within the natural gas industry and to help ensure that technically consistent interpretation occurs among the BLM personnel responsible for monitoring and enforcement.

Clarity is also important because without a concise understanding of the meaning of the rules, they become virtually impossible to follow.

Most of the natural gas measured in the United States occurs between private organizations including producers, gatherers, processors, pipeline companies, local distribution companies, end-users, and others. Gas measurement is most often based on standards and reports produced by the natural gas industry, usually developed through one or more of the industry organizations such as the API, AGA, GPA, and others. The writing of these standards and reports is an arduous task, based on technically supportable information originating from many different sources. In an effort to draw comments from many different resources, the API publishes its plan for the development of measurement standards in the Federal Register each year, thus allowing all interested parties to participate, including the BLM.

The proposed NTL falls short in several areas.

If the proposed NTL is going to provide exceptions to definitions currently included in the various measurement standards and accepted throughout the natural gas industry then the listing should be complete.

US Customs, MMS, and defense agencies all adopt API standards in whole with no exceptions, although API is pretty sympathetic to the fact of our limitations. API would still rather that BLM adopt the standards in whole. If BLM can make other exceptions to Onshore Order 5, maybe it can be done here.

Would like to reinforce what was said about other government bodies like DOE who use API standards as they are. BLM should not try to change the standard [21.1]

Comment 1A

Also, BLM should use the most current industry standard. In the future, wording should just refer to the "most recent standard".

Comment 2

The proposed NTL only addresses measurement by differential-type flow meters, whereas the industry standard API MPMS 21.1 covers all forms of gas measurement using electronic flow measurement.

Only differential-pressure flow meters are addressed in the proposed NTL. Because linear meters are sometimes used, they should also be addressed in the NTL.

Only differential-pressure flow meters are addressed in the proposed NTL. Since linear meters are sometimes used, they should also be addressed.

In reference to the, Item #2: Gas turbine flow meters and ultrasonic flow meters are used in Wyoming. There is no reference to the use of AGA No.7 for turbine meters or AGA No.9 for ultrasonic meters. Why does this NTL for electronic flow measurement not address linear and other types of ultrasonic meters in addition to square root meters?

Comment 3

Consistent interpretation of the proposed NTL by the BLM is very important especially for organizations operating in more than one geographical area in which the BLM has an interest. In the past, BLM representatives in different areas have been inconstant in their interpretation of some of the BLM rules and orders, thus resulting in increased operating costs and potentially causing a measurement bias.

Does this NTL apply to all of Wyoming and Nebraska state offices? Will the various BLM and State representatives interpret the NTL in the same way, and how will that be accomplished?" If this issue is not broached, then it will be up to each individual field representative to interpret the NTL in any number of different ways.

Inconsistency between inspectors, offices, and states in the enforcement of the NTL is a concern. To help with this Anadarko is willing to offer training to BLM.

Some inspectors will not try to find information if it isn't on a card even if the data is available on-site. We need to resolve this.

Comment 4

Previously approved variances should be "grandfathered" as previously done in Onshore Order No. 5.

Previously approved variances should be "grandfathered" as previously done in On-Shore Order Number 5.

Existing variances should be grandfathered and not replaced by the NTL

Comment 5

BLM should actively participate in standards development process to ensure their viewpoint is fully considered in the creation and revision of industry standards.

Industry thinks of the customers as owners of the materials that are produced, the consumers, the transportation industry, and basically everybody. This includes MMS, BLM, US Customs, and the military. All these government agencies except BLM have represented themselves in the API standard making process. BLM should join with API and the industry. If API and the industry know what BLM is thinking it can be addressed. API already submitted comments. Other standard setting organizations would welcome our participation - AGA in particular.

Western would suggest that BLM have more involvement with industry.

Devon encourages more BLM involvement in API committees.

AGA invites BLM to participate in the development of standards. The purpose of a standard to avoid confusion and wasting time and money. A standard is not developed just because that it is the way one person want to do it and therefore everyone should do it that way. AGA deals with many government organizations, and most include industry before proposing rule. This is a very good approach. AGA urges BLM to stop working on the NTL. Instead, send a letter to Jon Noxon asking that API 21.1 be revised to address the BLM concerns. API could probably issue a revised version of 21.1 faster than BLM can finalize the NTL.

Comment 5A

Devon is willing to help with BLMs accuracy goals.

Anadarko encourages BLM to include industry on the committee that finalizes the rule.

Comment 6

One example of this shortcoming is in the second paragraph of the proposed NTL where Pitot tubes are incompletely identified as a type of differential-pressure meter. Although certain differential-pressure meters incorporate some of the principles of a Pitot tube, some forms of Pitot tubes are not flow meters. Therefore, the referencing of a Pitot tube as a differential-pressure meter without further clarification is incomplete

The second paragraph of the proposed NTL identifies Pitot tubes as one type of differential-pressure meter. Although certain differential-pressure meters do incorporate some of the principles of a Pitot tube, some forms of Pitot tubes are not flow meters. Therefore, the referencing of a Pitot tube as a differential-pressure meter without further clarification is incomplete.

Pitot tubes are not differential pressure meters. They are velocity meters and should not be included.

Comment 7

Additionally, some flow meters that use Pitot tube principles have been shown to deviate significantly from published performance specifications when compared to independently developed flow calibration data.

The natural gas industry realizes that among all the differential producing meter types, only the performance of the concentric, sharp-edged orifice meter (as described in API MPMS Ch. 14.3, Parts 1 through 4), is based on well-documented empirical test data. All other differential meter types require flow calibration per current API measurement standards.

What Standard/Standards is this NTL referring to on venturi and pitot tubes? A concern exists on using this type of standard for these applications versus orifice meters.

Williams encourages BLM to note, by name and type, all differential pressure meters that are relevant. If they do not, then how can Williams and others know how to legally interpret the NTL?

The natural gas industry realizes that among all the differential producing meter types, only the performance of the concentric, sharp-edged orifice meter (as described in API MPMS Ch. 14.3, Parts 1 through 4), is based on well-documented empirical test data. All other differential meter types require flow calibration per a recently published API measurement standard.

The approval or disapproval of certain, possibly proprietary, natural gas measurement devices and methods not covered by industry standards for custody transfer measurement creates a dangerous precedent and should be discontinued.
The manufacturer, the make, the model, and the style of all differential-pressure meters covered by the proposed NTL should be provided. If an unabridged listing is not provided, then the NTL becomes impossible to interpret in a fair and consistent manner.

Comment 8

Another example occurs in the second paragraph where an electronic flow computer is identified as a secondary device, which is in conflict with the API MPMS Ch. 21.1 that clearly defines primary, secondary, and tertiary devices relative to electronic gas measurement.

The second paragraph incorrectly refers to an electronic flow computer as a secondary device, which is in conflict with the API MPMS Ch. 21.1 that clearly defines primary, secondary, and tertiary devices relative to electronic gas measurement.

For clarification, the secondary device is the transmitter/transducer transferring the physical pressures and temperatures into an electronic form. The tertiary device is the electronic flow computer that interprets the electronic signal and completes the on-site measurement. These definitions are outlined in API MPMS Ch. 21.1.

Comment 9

If the proposed NTL is going to provide exceptions to definitions currently included in various measurement standards as accepted throughout the natural gas industry, then the listing must be complete and unabbreviated.

Comment 10

In reference to the section Other Standards Incorporated by Reference, Item #1: Does Onshore order #5 still hold for natural gas measurement using chart recorders?

Comment 11

In reference to III.C.4 and III.C.5, industry standards should be followed for Electronic Flow Computers and Chart Recorders.

Comment 12

In reference to Item #2: By the definition of superseding or amending API, do the rules of API still apply and are the standards in the NTL considered additional requirements or in place of the API requirements?

Comment 13

Also, if a company's contract with another party requires the use of equipment that follows Industry Standards, such as those developed by the API and the AGA, do the BLM requirements negate the company's language in their contract? For example, in some cases where PODs are used for gas measurement on coal bed methane, does not some of the gas flow into a single flowing stream?

Comment 14

Any proposed NTL should read "Supercompressibility shall be determined in accordance with applicable industry standards".

It is inappropriate to make reference to AGA Report Number 3 or API Chapter 14, Section 3, for super-compressibility calculations. This reference should be deleted and only AGA Report Number 8 or NX-19 calculation methods should be referenced.

AGA Report No. 8 is cited in existing measurement standards for the calculation of gas compressibility. NX-19 is now obsolete and is known to produce erroneous results at some temperatures, pressures, and gas composition levels.

The combining of past and outdated measurement standards in the proposed NTL is misleading, technically unsound, and can lead to undue confusion and increased operating costs.

AGA Report No. 8 is cited in the measurement standards for the calculation of gas compressibility. NX-19, which is now obsolete, is known to produce erroneous results at some temperatures, pressures, and gas composition levels under BLM control. The mixing of past and outdated measurement standards in the proposed NTL is misleading, technically unsound, and can lead to undue confusion as well as lost revenue and increased operating costs.

In reference to Item #3: Supercompressibility is determined in accordance with AGA Report Number 8 and is referenced specifically in the API MPMS Ch. 14, Section 3, Part 3 for volume calculations. NX-19 is an outdated method (original development circa 1956 and published in 1962) for calculating compressibility and cannot be used in conjunction with the current orifice measurement standard. Allowing this to continue in new installations could cause inconsistent gas measurement and reduce the potential revenue to the BLM, Williams and to current and potential customers. Background information from AGA-8.1.2.

Comment 15

The requirement for a display on the EFC is an onerous and costly requirement. This requirement has nothing to do with correct measurement of the gas. The use of laptop computers and handheld devices are commonly accepted man machine interfaces in today's gas measurement industry.

These requirements are unreasonable due to cost associated with adding this function to the existing flow computers, which were installed with approval from the BLM. This function does not improve the accuracy or performance of the flow computers. Access to this data can be obtained with prior notice given or can be obtained real time through our SCADA system from the office.

All new units being installed have the screen display and I do not have a problem with requireing this for future units, but to upgrade existing units is very costly and adds no accuracy benefits.

In reference to Item #4: Superseding API standards results in increased measurement costs and affects the producers by pulling money away from increasing production. Williams views this as a cost to its customers that could be allocated for the development of production. This results in less revenue available for the development of production in Wyoming and, in turn, contributes to less revenue for the state and BLM.

Item 4 should exclude flowrate being part of the instantaneous display.

Item 4: The display doesn't necessarily tell you about the integrity of the meter. BLM needs to be in contact with the operator/calibrator who will know what the integrity of the meter is. For example, bent and nicked plates and 2-phase flow cannot be seen by looking at the display. There are other ways for BLM to get information. El Paso has on line data that could be used. BLM could be defined as user on the system and could do the calculations in the office.

Comment 16

As proposed by BLM, this requirement is onerous and costly and redundent to methods already in place. Industry recommends information requried by API MPMS 21.1 be obtained during BLM witness of calibration and audits performed by operating personnel.

BLM would be better served by requesting a copy of the monthly audit trail reports and attending the calibrations as a witness. Due to new security measures imposed by the Homeland Security Act, DOT and company policies it may not be possible in some cases to have the type of access that they want.

The Office of Homeland Security has made certain security requirements that might restrict access to the gas measurement equipment, and thus the requirement for a display may in certain instances, have no practical purpose.

Physical access to meter maybe limited by operational and safety conditions that exist and would place a liability risk on the operators. Operators are responsible to secure access to all equipment and meters, which in effect would protect the interests of all the parties to the transaction.

There are certain items that producers wish to remain "tight hole". Some of the proposed changes would be unwarranted. Realistically, the BLM should request data and the producer should be allowed to present it in a particular format (ie.. paper, spreadsheet, etc.)

Also, eliminating data collection units and/or laptops sounds nice, but its not practical.

The Homeland Security Act is going to make it a little harder to give BLM access to facilities. BLM may have to work out some kind of schedule with the operator. Also, there may be electrical code issues if you have to tie into meters with laptop.

Comment 17

Para 4 & 5 could be used to narrow the market for EFM hardware. We use Teleflows, and they are able to display the requested information. I don't know how many other vendors can provide the same display capability. It may be difficult to display all of this data on a 3330 with 3095s on each run.

The displays on most EFM devices have limits to how much information can be displayed. If requirements are adopted that require physical changes to the EFM display device, costs would be significant plus this is not practical.

Do not specify information to display beyond what is used now.

Comment 17A

Flowing information is already provided by previous regulations.

Comment 17B

Each audit report has this information included.

Comment 18

Most RTUs deployed and manufactured have limited display capabilities. Information such as make, range and model number of each transducer/transmitter is not normally input (if any fields exist in the software). Most displays have limits as to the amount of characters per line (a typical transducer serial number may have 15 digits and display can only show 12). The BLM by regulation has witness rights and can access this information during the witness process.

Comment 19

5) The following statement should be added for clarification: “This requirement may be satisfied by the maintenance of a print out of the EFC configuration data. The properties of the gas may vary over time. If live inputs for gas properties are not used, then the specific gravity, inert component mole percents, and heating value shall be the values used in the flow calculation based on the latest available gas analysis, which in some cases could be determined on an annual basis.

The following statement should be added for clarification: “This requirement may be satisfied by the maintenance of a print out of the EFC configuration data.”

The values used for on-site calculations could be included with the current instantaneous values of static pressure, differential pressure, and flowing temperature, on the EFC display, only to prevent the need for duplicate logging.

Orifice plate changes may occur relatively frequently and perhaps a separate log should be maintained for these, showing dates, times, from, to, and by whom.

The requirement that certain information including meter tube inside diameter, transducer specifications, and pressure tap location, etc., is unclear and should be further addressed and defined. The various options for displaying this information should be clarified.

In reference to Item #5: What form of media (paper, laminated, plastic, stickers, etc) would be needed to meet this requirement? Will the BLM require the information to be typed or printed, or will hand-written information be accepted? The additional expense brought about by this change would be passed along to Williams' customers, and others, which would otherwise be allocated for the development of production. This Item would result in less revenue available for the development of production in Wyoming and less revenue for the state and BLM.

Why does the meter run inside diameter need to be maintained as a document?

The Make and model number can be determined by looking at the transducer/transmitter physically on location. What is the advantage of documenting this on location?
Instead of onsite records, copies of calibration sheets are available to all interested parties. These reports contain all the information requested onsite.

The requirement that certain information including meter tube inside diameter, transducer specifications, and pressure tap location is unclear and should be further addressed and defined. The various options for displaying this information should be clarified.

Comment 20

The physical location of the flowing (static) pressure (upstream or downstream) is indicated on the transducer. What is the advantage of documenting this on location? Can be determined by inspection?

Comment 21

The properties of the gas may vary over time. If live inputs for gas properties are not used, then the specific gravity, inert component mole percents, and heating value shall be the values used in the flow calculation based on the latest available gas analysis, which in some cases could be determined on an annual basis.

Among other things, the orifice plate and relative density (specific gravity) will be required to be maintained on site and available without the need for special equipment. The relative density may be adjusted by periodic recalculation off-site and the value maintained in a hardcopy record on-site may not reflect the value actually used for invoicing.

Other system configurations are not likely to change within an EFC. By listing some in the proposed changes to Chapter 21.1 we may be missing still others. As well, what is in a paper log beside an EFC may not be what is actually in the EFC. It may be best for the BLM personnel to visit metering sites together with Measurement Technicians that have the necessary equipment to view and verify the EFC configuration data.

Comment 22

Maintaining information onsite adds more confusion. Where is onsite defined? If onsite is defined as on location, then a calibration sheets/records must be maintained on location. In this is so, then the EFM device must be put in a building. Due to electrical classifications, EFM devices CANNOT be put into Class 1 Division 2 buildings. Not only that, it is not safe for untrained personnel to enter such buildings. In Wyoming, the wind makes putting such things outside very unrealistic. Leaving calibration records in field offices is the correct place. Placing this information at the meter run is NOT the correct place.

Do not specify that calibration sheets/records be kept on site.

In other cases, the producer/gas gatherer have contracts that allow the gatherer to collect and store the data. Some even have cases where only the gas gatherer has direct access to the EFM device. In some cases, the gas gatherer is set up to store data that nobody else is.

Allow gas gatherers and producers to work together to supply information to the BLM. The BLM should request the format that the data be delivered in.

Comment 23

Will this requirement need to be maintained in off/on site records storage for six years as stated in Item #6? There is a cost associated for each stored record.

Comment 24

The proposed 43 CFR 3100 (page 66842, dated 12/3/98), which is currently out for comments, references a seven-year data retention period. This is in conflict with the proposed NTL

In reference to Item #6: The new proposed 43 CFR 3100 page 66842 (dated 12/3/98), currently out for comments, references seven (7) years for data retention – It references the federal oil and gas royalty application and fairness act of 1996. This Item #6 is a discrepancy for data retention from the proposed 43 CFR 3100. Can you please clarify the difference in the timeframe for data retention?

Comment 25

Industry recommends the data retention period be consistent with existing governmental regulations (FERC), which requires three years of data retention.

The requirement for 6 years of data archival is onerous and excessive, given that the Federal Energy Regulatory Commission (FERC) only requires 3 years of data archival, and that the requirements of the Gas Industry Standards Board require meter error settlement within 6 months of discovery. This requirement has further been clarified by FERC as a reasonable cut off point for disputed metered volume settlement for events of unknown origin in time.

Comment 26

In reference to Item #7: Please explain the meaning of installation instructions, calibration procedures, software and algorithm details, and technical specifications? There are numerous sources for this data. Which source matches the expectations of the BLM?

Additional clarification is needed regarding the requirement for installation instructions, calibration procedures, software and algorithm details, and technical specifications.

Comment 27

Installation instructions, calibration procedures, and technical specifications can be made available upon request. However, software and algorithm details are privately held and proprietary and cannot be made available except through the owner of the software.

The information provided will need to be obtained from the manufacturer of the EFC and some data could be proprietary, such as the software and algorithm details. The purchase of this data may be required, such as a site license.

Regarding specifically the software and algorithm details, many manufacturers of flow computers view this information as proprietary.

Item 7: "Software algorithms" are typically copyrighted materials. Even though software is purchased, the operator or purchaser does not own it. It would violate copyright rules if they redistributed the software to BLM. BLM needs to take that out of the NTL. When a piece of equipment is purchased you buy a software package that communicates with the device. You can't look at the actual software. The manufacturer owns the intellectual property.

Comment 28

Para 8 & 10 do not address the difference between a full calibration and a zero / line pressure check. It doesn't make sense to continually run checks to full transmitter range for low flow meters. A program of verification at zero and line conditions with appropriate full calibrations makes more sense.

The requirement for a full span “as found” verification of pressure transmitters is not reasonable. The “as found” verification requirement should be changed to allow “determination of as found pressures as indicated on the EFC at line pressure, 50% of line pressure, and zero pressure. If the values found are not within the manufacturer’s stated tolerances, then a full span calibration is required.”

The requirement to have additional equipment or high pressure supplies for the pressure transmitter verification is excessive and unwarranted.

Comment 29

API 21.1 is the recommenced minimum specification when utilizing electronic flow computers. The purpose of the recommended calibration and verification of transducers is to ascertain the accuracy, reproducibility and hysteresis. Not only is the transducer performance tested by the recommendations in API 21.1, all related electrical and electronics are tested as well. The proposed “As found” readings in the BLM draft minimizes the ability to determine if the transducer and related electronics (cabling and A/D converter) are functioning properly. This will not improve measurement. If the measurement device is not linear throughout the recommended 0, 50, 100, 80, 20 and 0% check points, the device is defective and will be replaced. If the device is found to be out of specification, then a calibration is performed and another series of check points are run to establish the “As Left” condition to further verify that the secondary devices and related electrical components are within tolerances.

In reference to Item #8 & #10: The calibration of the as-found/as-left portion in this NTL does not supersede API requirements as stated for Item #8 and #10. This requirement will not meet the current minimum specification required in API MPMS 21.1. API has more points and may represent a more accurate calibration. By evaluating the linearity of going up and down, the full scale of calibration results could potentially resolve hysteresis issues during calibrations. Failing to complete secondary equipment calibration as recommended by the API MPMS Ch. 21.1, will potentially cause measurement inaccuracies that will result in potential revenue losses to the BLM and Williams.

The proposed NTL detracts from API 21.1 by reducing the minimum requirements in the Calibration and Verification section on pressure and differential measurement elements. API 21.1 supports additional pressure “as found” and “as left” data points and leaves additional data points up to the end users. The recommended practice is designed to test the secondary devices over the full operating range and to assure that hysterisis does not occur. The proposed zero, full scale and a point representative of the nominal operational static or differential pressure does not adequately test the secondary instrumentation. This will provide error in measurement that is not acceptable to the natural gas industry.

Comment 30

Does the NTL also supersede Company contracts that follow API Standards that are more stringent and have been previously agreed to by both interested parties?

Comment 31

There are many transducers on the market that are not all equal. This statement may result in the purposeful selection of the lower end transducers available which again will not provide for better measurement.
A suggestion to quantify a reasonable tolerance (0.1 to 0.25% error) would allow the lessee/operators to be on equal footing and provide a manageable witnessing program.

Comment 32

The proposed changes include a statement that if the meter during calibration is off by more than the stated accuracy of the meter/transducer, the meter must be recalibrated. This is very tight and ignores that there are other factors affecting as found and as left values. For example, the accuracy/performance of the calibration equipment should not be ignored.

Comment 33

Also, on the static transducer, changes in atmospheric pressure, relative to a fixed assumed/contractual atmospheric pressure may cause the static transducer to appear to be out of calibration, when actually it's working fine.

It may require using actual measured barometric pressure during calibration/verification to avoid frequent recalibrations. It can be done with wrist barometers, but it's not a common practice.

Comment 34

Perhaps the changes should require recalibration if the combined uncertainty of the meter/transducer and the calibration equipment is exceeded, but this would still not address atmospheric pressure variation on the static transducers

Comment 35

As stated in comments on item 8, a full span calibration of the pressure should only be necessary if the as found indication shows the transmitter to be out of tolerance.

Comment 36

In reference to Item #9: How does this amend API 21.1.1.8.3?

Comment 36A

Many vendor specified performance of devices do not meet the precision requirements stated in the product specification sheet. The ambient temperature on the electronic housing affect the output of the transmitter must be considered in tranducer/transmitter allowable calibration limit. The influence of the differenctial pressure reading on the volume measure is half (square root dependence), so the limits of the "as found"/"as left" should be extended to a value as a percentage of the full scale and span reading of the device and not the performance specification defined on the manufacturer's product specification sheet. Based on the limits of the volume measure, the limit of DP device should be extended to higher limits of the full scale, which will take into account the temperature influence of the processing electronics. The mid-point reading is a function of zero and span adjustments and is not independently adjustable, unless curve fitted.

Comment 37

API 21.1 is the recommenced minimum specification when utilizing electronic flow computers. The purpose of the recommended calibration and verification of transducers is to ascertain the accuracy, reproducibility and hysteresis. Not only is the transducer performance tested by the recommendations in API 21.1, all related electrical and electronics are tested as well. The proposed “As found” readings in the BLM draft minimizes the ability to determine if the transducer and related electronics (cabling and A/D converter) are functioning properly. This will not improve measurement. If the measurement device is not linear throughout the recommended 0, 50, 100, 80, 20 and 0% check points, the device is defective and will be replaced. If the device is found to be out of specification, then a calibration is performed and another series of check points are run to establish the “As Left” condition to further verify that the secondary devices and related electrical components are within tolerances. Follow API 21.1

In reference to Item #8 & #10: The calibration of the as-found/as-left portion in this NTL does not supersede API requirements as stated for Item #8 and #10. This requirement will not meet the current minimum specification required in API MPMS 21.1. API has more points and may represent a more accurate calibration. By evaluating the linearity of going up and down, the full scale of calibration results could potentially resolve hysteresis issues during calibrations. Failing to complete secondary equipment calibration as recommended by the API MPMS Ch. 21.1, will potentially cause measurement inaccuracies that will result in potential revenue losses to the BLM and

Williams. Does the NTL also supersede Company contracts that follow API Standards that are more stringent and have been previously agreed to by both interested parties?

The proposed NTL detracts from API 21.1 by reducing the minimum requirements in the Calibration and Verification section on pressure and differential measurement elements. API 21.1 supports additional pressure “as found” and “as left” data points and leaves additional data points up to the end users. The recommended practice is designed to test the secondary devices over the full operating range and to assure that hysterisis does not occur. The proposed zero, full scale and a point representative of the nominal operational static or differential pressure does not adequately test the secondary instrumentation. This will provide error in measurement that is not acceptable to the natural gas industry.

Comment 38

Transmitter repair or replacement should be extended to 72 hours.

Also the change should be 7 days and not 48 hours.

Comment 39

In reference to Item #11 & #13: Williams would like to understand the 48-hour time frame. Is this abatement period and after 48 hours, if the meter could not be repaired, would this require the meter to be shut-in? Shutting in a meter and / or well could affect production and would affect revenue for the BLM and other interested parties. Williams is trying to understand the time frame to avoid any notice of violations.

Comment 39A

Industry recommends the time period for repair should be consistent with Onshore Order No. 5.

Comment 39B

The contribution of the error to the total flow volume measured by the meter should be condered in applying mandetory change of the transmitter/transducer.

Comment 40

Para 12 should allow hot and cold water baths to verify calibration. Old runs may not have test wells.

Item 12 should allow for hot and cold bath…

Comment 41

API 21.1 addresses this issue. It also addresses that in is not possible to temperature calibrate the device. A temperature calibration consists of using a certified resistance decade box and challenging the electronics at the zero, half scale, full scale, half scale and zero (to again assure no hysteresis is present). Not many decade boxes have the luxury of having a variable output, they usually have fixed values. An RTD is a linear device (platinum resistor) and if it fails, it is usually open or many degrees off. If this occurs the prudent operator replaces the device immediately.

Item 12 should allow…for electronic simulation

Comment 42

The document does not address legacy installations that may not have a temp well located near the EFM device. How is going to be determined if the device is measuring accurately if it is not in the same flow stream? The cost of retrofitting or installing new meters may be prohibitive. Page one notes that EFCs previously approved shall be granted a one-year grace period, from the issuance of the standard, to bring those EFC’s into compliance.

Comment 43

In reference to Item #12: How does this amend API 21.1.8.3.1.4?

Comment 44

Precision required of a temperature transmitter calibration is of concern. Stated precision of BLM Order 5 is overly conservative as it is not necessary for the stated measurement accuracy. One degree Fahrenheit error in temperature reading contributes to about 0.2% in volume reading. Why the precision needs to be half a degree which may contribute a maximum volume error of 0.1% when allowable error limit is 2%? The precision is also dependent on the perfromance specifications of the installed device. The preferred temperature verification limit near the normal flowing temperature should be +/- 1 degree F or limit of the precision of installed device, if greater than 1 degree F, but must not exceed +/- 2 degrees F.

As left The temperature transducer/transmitter are not within 2 degree F of the test thermometer, the temperature transducer/transmitter shall be replaced within 7 days.

The tolerance for temperature error is too small. A 1% error in temperature measurement will produce a 0.1% flow error. The temperature measurement error should be changed to a 1% value.

Item 13: The requirement for the temperature to read within 0.5 degree is too stringent, even though it is in 21.1. Considering 3% uncertainty, 0.5 degrees is too onerous of a requirement. El Paso suggests 1 degree, instead.

Comment 45

The 48 hour requirement for repair or replacement of a failed transmitter should be changed to 72 hours.

Comment 46

In reference to Item #11 & #13: Williams would like to understand the 48-hour time frame. Is this abatement period and after 48 hours, if the meter could not be repaired, would this require the meter to be shut-in? Shutting in a meter and / or well could affect production and would affect revenue for the BLM and other interested parties. Williams is trying to understand the time frame to avoid any notice of violations.

Comment 47

Para 14 & 15 are not consistent. Design to 3% error limits with required recalibration to <2% makes no sense.

Comment 48

The limit of the measurement must be scaled for high and low flow rate and flow volume values and not by a blanket statement of 2% or 3% of the normal flow rate reading.

Comment 49

The last sentence should be changed to read:
"If this time is unknown, volumes shall be corrected for the last half of the period elapsed since the date of last verification or calibration."
Verification may be distinguished as the activity determining as found condition. A calibration may be distinguished by the fact that the device reading is being adjusted to a known standard

Industry recommends replacing verification for calibration in the last sentence.

Item 14: Need to differentiate verification and calibration. Verification is an as found test. Calibration is changing the performance of the transmitter. Calibration is thrown in throughout the document. In some cases BLM might want to go back to the previous verification, not necessarily the previous calibration.

Comment 50

In reference to Item #14: Williams has recognized the calibration adjustment of greater than 2.0% to correct for calibration error from electronic flow computers. However, Williams has also recognized correction to volumes that are less than +/- 100-250 MMBTU as an administrative burden. Netting the actual adjustment value to correct the calibration adjustment will cost more than the value realized. Williams requests a minimum MMBTU in the above stated range to alleviate any costly volume adjustments that do not add value.

Industry recommends no adjustment be required for accumulated energy of 100 MMBTU or less per accounting period.

Item 14: There should be an economic limitation in adjusting volumes. Instead of a 2% threshold, it should be volume based (100 MMBTU per cycle). It is a waste of time and money to chase down 2% errors on low volume wells.

Comment 51

The idea that we would calculate a system uncertainty for each installation and maintain those calculations for an auditor is unreasonable.

Comment 52

"For meters measuring more than 100 Mcf per day on a monthly basis, the EFC shall be installed, operated, and maintained to achieve an overall measurement uncertainty of "3%, or better, of true flowrate. The calculation of uncertainty shall be done in accordance with AGA Report 3, Part 1, 1991, or other method that has been approved by the authorized officer. BLM may prescribe operating limits to implement this requirement."
It is unclear exactly what components of a measurement system are included in the overall measurement uncertainly, these components need to specified.

The BLM needs to provide a method and identifying a program to calculate the overall measurement uncertainty.

In reference to Item #15: Williams requests more clarification on the calculation of uncertainty for all meters. In order to fully develop the calculations, the BLM would need to specifically develop a list of calculation parameters to be included, such as detailed scope defining the uncertainty, describing what is included in the 3.0%, and determining the type of acceptable calculations that are used to determine the 3%

The calculation of overall measurement uncertainty is a complex subject and the proposed NTL is extremely vague in this area. Before any meaningful comments can be made to this issue, additional clarification is needed. One way to address this would be for the BLM to provide a listing of specific parameters and proposed calculation methods to be used.

Need more information on how the 3% uncertainty would work.

There are a lot of considerations when calculating uncertainty. The "Guide to Uncertainty in Measurement" (ISO 1297) should be used. The appendix in 14.3 is a excerpt form ISO standard.

Comment 53

The calculation of uncertainty stated in AGA Report 3, Part 1, 1991 only covers the uncertainty of the AGA 3 equations, it does not provide a method of calculation for the overall measurement uncertainly of the complete system.

Comment 54

The accuracy requirement in Item 15 is made specific to the EFC uncertainty only and is very large for a calculation uncertainty.

Comment 55

Uncertainty requirements should be expressed for both volumetric and energy rate measurements.

Comment 56

[The BLM would need to specify] the need for 3rd party certification with their calculated uncertainty and installation uncertainty (EFC, tubing, testing equipment, etc).
Will the BLM require 3rd party testing to verify the accuracy of the volume calculation per API MPMS Ch. 14.3, Parts 1, 2, and 3, and the audit trail requirements of the EFC per API MPMS Ch. 21.1, or can all EFCs be used without any third party testing? Williams uses third party testing through CEESI, Southwest Research Institute and Stark & Associates, Inc. for confirmation of correct volume calculations. The use of any EFC could provide an unfair advantage to parties not using 3rd party tested EFCs that do not adhere to Industry Standards and could possibly contribute to the calculation of an incorrect volume.

Comment 57

The calculation of overall measurement uncertainty is a complex topic and is subject to the whims and opinions of the individuals performing the calculations. The proposed NTL is vague in this area and additional clarification is needed before any meaningful comments can be made. Since the calculation of measurement uncertainty is a theoretical exercise based on the opinion of individuals performing the uncertainty calculations, the determination of measurement uncertainty does not always provide practical and useable information relating to flow measurement.

Comment 58

Industry recommends this item be deleted because “true flow” is unknown. Uncertainty should be defined in terms of a confidence level.

Comment 58A

Another issue is the current operating pressure versus the span of the transmitter. A limit on the allowable span of the pressure device would be a better approach.

Consider 5% of scale rather than what manufacturer states. For example, the 1151 is a real problem and should be set at 5”.

EFCs should operate with a differential pressure above 10” whenever possible and static pressure should be above 10 % of range.

Transmitters should not be operated down at very low differential pressures where the low flow cutoff would be an issue.

Comment 59

Williams has found that a practical setting is 0.5 inches of water. Pulsation, nicked or dull orifice plates, flow conditioner obstruction creating a flow distribution problem, obstructed tap holes, damaged or incorrect seal orifice seal plate rings, wrong plate thickness, and line surge changes have demonstrated the value of 0.5 inches of water as a practical value for orifice measurement. Also, manufactures' zero shift tolerances might not support this recommendation.

Comment 60

Because the establishment of any set or fixed low-flow cutoff is impractical, this part of the NTL should be discussed further in order to develop a workable solution

Williams strongly recommends this current NTL practice set for low flow cutoff be revised to something more practical to alleviate the above stated measurement issues.

Because the establishment of any set or fixed low-flow cutoff is impractical, this part of the NTL should be discussed further in order to develop a workable solution.

Want a low flow cutoff that is supported by industry. EOG agree that 0.5" is a reasonable value.

Comment 61

The real issue is apparent flow in runs where no gas is really flowing. That can be tied to temperature affects, A/D conversion issues etc. A standard cutoff of .5 in wc would make more sense.

In the examples of calibration and low flow cut off provided, the equipment manufacturers specifications were to be used as a basis for calculating tolerances. As much as the manufacturers do strive for accuracy in specifications, they do not always meet their target. As well, in the processes of transmission and conversion there are additional uncertainties that should be considered. API Chapter 21.1 working groups generally represent industry experiences and invite regulatory participation. We agree that a specification should be given, just that it may best come from API itself.

Low-flow cutoff requirements as explained in the proposed NTL are technically unsound and do not conform to API MPMS Ch. 21.1. Transducer performance, especially at the lower end of the scale, depends on many variables, including individual characteristics which are affected by specific design, manufacturing tolerances, operating conditions, and time in service.
In reference to Item #16: Williams requests clarification regarding the requirement for low flow cutoff because the various equipment manufacturers have a variety of specifications. There are different manufactures with different specifications that result in different accuracy of differential transducers. Some manufactures have a zero shift of 0.3% and some can be 0.5% and 0.7%. Transducer performance depends on many factors, some of which depend on specific design and manufacturing tolerances. Williams considers this NTL requirement a non-fair standard practice that is not technically practical

Low-flow cutoff requirements as explained in the proposed NTL are technically unsound and do not conform to API MPMS Ch. 21.1. Transducer performance, especially at the lower end of the scale, depends on many variables, including individual characteristics which are affected by specific design, manufacturing tolerances, operating conditions, and time in service.

Comment 62

This requirement may not be practical when the site has compression located upstream or downstream of the facility. In that case, a procedure for shut in test is recommended for determining flow cutoff value.
The preferred technique is to close the downstream block valve and observe the differential pressure that is indicated at zero flow rate.

Vibration or noise from compressors or plunger cycles can mimic a rise in differential pressure and thus cause inaccuracies with a low differential flow cutoff.

Item 16: There is no relation between accuracy and low flow cut off in the real world. An accurate transmitter can show flow because of noise when the low flow cutoff is below 0.5". Liquid can also affect the transmitter below

0.5". Devon recommends a low flow cutoff set at 0.5", otherwise the EFC will show flow when there is not flow. This will cause many economic problems.

Item 16: Most transmitter accuracy specifications are under lab conditions. When they are put in the field, they experience more noise which can lead to false readings of differential pressure. Setting low flow cutoff on a case by case basis is very time consuming.

Item 16: As an example of low flow cutoff, consider a 2-run meter switching situation with a flow computer that does a meter tube switch at 10% and 90%. For instance, when the first tube reads 90", the second tube is switched in. At10", the second tube is switched off. If there is a compressor near the location and if DP shows transients due to noise even if block valve is closed, then you know it is zero flow.

Comment 63

Para 16 confuses equipment accuracy with low flow issues. As you point out, buyers would want to use the lowest accuracy devices available, while sellers would want the highest to gain benefit from the low flow cutoff

Comment 64

Industry recommends following API MPMS Chapter 21.1, which states in paragraph 4.2.3 "A low flow cut off point for differential meters should be determined by the contractually concerned parties based upon a realistic assessment of site conditions."

The simplest thing would be to set the cutoff high enough to block the false reading because you know there is not flow. In a single run, compression might show noise. The operator should be able to set the run per operating conditions. The low flow cutoff needs to be evaluated on a site by site basis because there is more to it than just the theoretical performance of the equipment.

Comment 65

WGR requests Onshore Order No. 5 part III sec. C.17 be waived and new standards relating to EFC's be implemented as part of the NTL document establishing the meter testing frequency at a semi-annual minimum requirement. Currently an interval extension requires approval from an authorized officer and has been limited to wells producing less than 100 mcf/d rates. The published accuracy of the EFC devices are well within the mininum guidelines established in the NTL, also calibration histroy would indicate EFC stability has met these criteria in the reduced amount of calibration adjustments being performed. A comparision test between a random sampling of meter tests performed over the last two years on existing production across the state produced these results. The meters tested at 3 month intervals produced an avg. meter error of 0.063%, while the meter group tested at 6 month intervals produced an avg. meter error of 0.044% (Please see attached source documents). Implementing the semi-annual calibration frequency – would reduce the administrative burden on BLM personnel as well as provide incentive to industry to install EFC measurement on low volume wellhead sites.

Western supports all comments submitted by API and feels the NTL is timely. Suggest Onshore Order 5 Part III, C.17 be waived to require semi annual testing instead of quarterly testing. So far, semiannual testing requires a variance and has been limited to meters measuring less than 100 Mcf/day. Published accuracies of EFCs are well within the guidelines of the NTL and calibration history would indicate EFC stability has met this criterion in the reduced amount of calibration adjustments being performed. Western has run a comparison of reduced calibrations. Based on random sampling, the average error discovered on meters being calibrated quarterly was 0.063%. For meters being calibrated semiannually, the average error was 0.044%. Implementation of 6-month would reduce administrative burden on BLM as well as provide incentive to install EFCs on low volume well sites.

BLM should be careful in accepting a 6-month calibration for EFCs since they aren't "god's answer" to measurement.

Williams supports a 6-month calibration schedule if agreed on between the operator and the buyer.. EFCs have been proven to be reliable and repeatable. Williams has provided support to numerous BLM offices for a lowering of calibration frequency to 6 months.

EOG recommends a semi-annual calibration requirement instead of quarterly.

EFCs are so accurate that calibrations can be extended, but EFCs are no more accurate than the primary element. Anadarko is not supportive of extending orifice inspections.

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Note: Italicized comments are synopses of verbal comments received at the Public Hearing held on December 18, 2004, in Casper, Wyoming.